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VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: UM 2024—PacifiCorp's Opening Comments

PacifiCorp d/b/a Pacific Power encloses for filing its opening comments in the above-referenced proceeding.

If you have questions about this filing, please contact Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS Petition for Investigation into Long-Term Direct Access Programs.	PACIFICORP'S OPENING COMMENTS

PacifiCorp appreciates the opportunity to file these comments in response to the Phase I Stipulated Issues List issued in this docket on February 21, 2020. In this phase of the docket, the parties have been asked to comment on several direct-access issues that are important to the implementation of direct access policies. These include the potential benefits and potential costs to customers of long-term direct access, the manner in which other states are handling direct access issues, and, importantly, resource adequacy issues. PacifiCorp looks forward to engaging on these and other issues in this docket.[1]

I. Background of Oregon's Direct Access Law — SB 1149

The Oregon Legislature enacted Senate Bill (SB) 1149 in 1999. In the late 1990s, Oregon, along with other states, showed interest in the potential benefits of retail electric market competition. Retail electric prices were high in the 1990s, due in part to cost overruns and failed investment in nuclear plants in the prior decade.[2] The falling cost of gas plants, along with the Federal Energy Regulatory Commission's (FERC) deregulation of the wholesale electric market, led many customers, particularly industrial customers, to believe that retail competition would bring benefits in the form of lower costs.[3]

SB 1149 was designed to deregulate the retail electric energy service in Oregon and to allow the development of some elements of a competitive retail electricity market. As the Oregon Legislature stated in the preamble to SB 1149:

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[1] The first phase of this docket is a comment phase, with reply comments to be filed on April 6, 2020. The second phase is currently envisioned to be a legal-briefing phase, followed by a contested-case phase.
[2] *See, e.g.,* Richard J. Pierce, Jr., *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity,* 132 U. Pa. L. Rev. 497 (1984) (describing national and state energy policies that led to canceled nuclear plants).
[3] David B. Spence, *Realizing the Promise of Elec. Deregulation: Article: The Politics of Elec. Restructuring: Theory vs. Practice*, 40 Wake Forest L. Rev. 417, 446-47 (2005) ("In most restructuring states, restructuring was driven by industrial customers who believed that they subsidized other customer classes under regulated rate tariffs and that they could get better rates on a competitive market.").

> Whereas the divestiture or functional separation of electrical power generation from the distribution functions is the most effective means of stimulating competition, providing depth and liquidity to the wholesale market and facilitating the transition to a fully competitive market by alleviating horizontal and vertical monopoly market power and providing a more accurate estimation and mitigation of stranded costs; and
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> Whereas price and service unbundling is the best way to identify the costs associated with generation, transmission and distribution of electricity services and is essential to the development of a competitive market; and [. . .]
>
> Whereas all Oregon retail electricity consumers should be provided fair, non-discriminatory access to competitive electricity options [. . . .][4]

The law gave the Public Utility Commission of Oregon (Commission) authority to require utilities to make implementation filings,[5] subject to the mandate that the "provision of direct access to some retail electricity customers must not cause the unwarranted shifting of costs to other retail electricity consumers of the electric company."[6] The Commission implemented this statute through rules requiring electric utility consumers to receive a credit or pay transition charges "equal to 100 percent of the net value of the Oregon share of all [investments] as determined pursuant to an auction, an administrative valuation, or an ongoing valuation."[7]

Notably, the law in Oregon, unlike the laws in some states, did not purport to move all customers to "competitive" retail options. Residential and small retail customers would instead be permitted to choose from a "portfolio" of options that remained subject to the full regulatory authority of the Commission.[8] The result of SB 1149 was to provide smaller customers with a suite of regulated options, and a limited subset of larger customers with a direct-access option—as long as that direct access created "no unwarranted cost shifting" and met other statutory requirements.

The Western Energy Crisis of 2000-2001 halted the movement toward fully competitive retail electricity markets in much of the nation.[9] Two years after SB 1149 was adopted, the Oregon

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[4] SB 1149, 70th Or. Leg. Assemb., Reg. Sess. (1999) (preamble).
[5] SB 1149, Sec. 20; ORS 757.661.
[6] SB 1149, Sec. 8; ORS 757.607(1). The cost-shifting statute is written broadly and does not limit its protection to Oregon customers. For a multi-state utility like PacifiCorp, this means the impact on customers from other states is a relevant consideration.
[7] OAR 860-038-0160(1).
[8] SB 1149, Sec. 4; ORS 757.603(2); OAR 860-038-0220. The portfolio option was supported by the Oregon Citizens' Utility Board (CUB), and by a broad stakeholder group called the Fair and Clean Energy Coalition. CUB disputed the idea that retail deregulation would bring benefits for smaller customers and opposed proposed legislation that would "do away entirely with regulated rates and throw everyone into a retail market with almost no rules or protection." CUB, "You'll Have the Power," *The Bear Facts*, Fall 1998, at 5, available at https://oregoncub.org/images/uploads-legacy/pdfs/1998-3-FallOCR.pdf. For smaller customers, CUB argued, "[w]e want to keep the existing protections, yet still give consumers options and the information necessary to make informed choices." *Id*.
[9] "The Energy Crisis brought California blackouts and economic hardship. In 1999, the first full year of deregulation, Californians paid $7.4 billion for wholesale electricity. A year later, those costs rose 277 percent—

Legislature amended SB 1149 by enacting House Bill (HB) 3633, which (1) delayed SB 1149's effective date and (2) required the state's two largest investor-owned utilities to continue to offer all customers a cost-of-service rate.[10] Additional legislation was passed that same year, intended to ensure there were adequate regulatory incentives to build new generation in light of existing scarcity.[11] That legislation, enacted only two years after SB 1149, contained introductory clauses reflecting a far different energy landscape:

> Whereas the western United States is experiencing a shortage of electrical generating capacity, and as a result consumers in Oregon are faced with the prospect of significant increases in the cost of electricity; and
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> Whereas wholesale power markets in the western United States are reflecting extreme price volatility, and there is substantial uncertainty with respect to the level of wholesale electricity prices in the future; and
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> Whereas there is considerable uncertainty about the extent to which electric companies will be called upon to supply electricity to Oregon consumers at cost-based rates; and
>
> Whereas the current regulation of electric companies and electric services may not sufficiently promote the development of new electric generating resources; and
>
> Whereas in the current economic and regulatory environment, electric companies face substantial risk in respect to the construction or acquisition of new electric generating resources; and
>
> Whereas the Public Utility Commission has the unique expertise to understand and lead changes in the regulation of electric companies that are necessary to further the purpose of this 2001 Act for the benefit of Oregon consumers [. . . .][12]

Since then, the Oregon Legislature has neither moved to extend direct access to additional customer classes, nor repealed the existing direct access provisions of SB 1149. Instead, the Legislature has continued to ask the Commission to exercise its "unique expertise" to implement the existing direct access statutes in a manner that protects customers' access to safe, reliable, affordable electricity, and to do so in harmony with other Commission obligations—including its implementation of other laws intended to move the state toward its energy policy goals.[13]

Oregon thus continues as a state with a partially deregulated retail electric market. It remains a piecemeal system with no market monitoring function other than the Commission's oversight. Oregon's version of direct access therefore requires continuous, vigorous Commission review

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$27.1 billion. In 2001, wholesale power costs held fast at the exorbitantly high level of $26.7 billion." Cal. Att'y Gen., *Attorney General's Energy White Paper* at 6 (Apr. 2004), available at https://oag.ca.gov/sites/all/files/agweb/pdfs/publications/energywhitepaper.pdf.

[10] HB 3633, 71st Or. Leg. Assemb., Reg. Sess., Secs. 1 and 2 (2001); *see also In the Matter of a Rulemaking to Modify OAR 860-038-004(23)*, Docket AR 394, Order No. 02-053 at 3 (Jan. 28, 2002).

[11] HB 3696, 71st Or. Leg. Assemb., Reg. Sess. (2001).

[12] HB 3696 (preamble).

[13] *Id.*

and enforcement to ensure that the departure of large commercial and industrial customers from the system does not harm the state's remaining retail customers.

II. What Are the Potential Benefits and Potential Costs to Customers from Long-Term Direct Access[14] Participation?

Direct energy purchasing by large customers can increase costs for other ratepayers, as these large customers "defect" from existing utility-procured resources, leaving a smaller pool of ratepayers to cover embedded costs.[15] Ongoing capital investments or operational costs needed to provide reliable service within a Balancing Authority Area (BAA) can also be unfairly shifted to utility customers if third-party providers are not required to carry those reliability obligations in equal measure.[16] In addition, various state public policy and legislative mandates must be implemented by utilities, even when those mandates cause utilities to incur above-market costs. By increasing utility system costs, these mandates create additional financial incentives for mobile customers to exit the system, which can leave a smaller and smaller pool of remaining customers responsible for financing statewide energy policy goals.[17]

If significant customer load departs the system under direct access, and remaining customers are not financially protected from the departure of that customer load, the following are illustrative of the types of costs that can be shifted to remaining utility customers:

- Stranded costs associated with system assets that were acquired by the utility to serve customers but are no longer needed to serve departing customer loads.
- Stranded costs associated with higher-cost but prudently incurred legacy contracts, such as long-term contracts needed to serve load or meet Renewable Portfolio Standards (RPS) requirements, executed when natural gas prices were higher and/or before the steep decline in renewable energy prices.
- Stranded costs associated with contributions towards eventual power plant decommissioning and environmental remediation costs.
- Ongoing costs associated with the continued need to plan for the potential return of departing customers.
- Ongoing costs associated with short- and long-term grid reliability, if reliability obligations are housed with utilities rather than fairly allocated between utilities and third-party providers.[18]

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[14] Also called "retail access," "customer choice," "retail competition," and "retail wheeling."

[15] Advanced Energy Economy (AEE) Report on Policies to Expand Corporate Access to Advanced Energy at 16-17 (2018), available at: https://info.aee.net/hubfs/AEE_July2018/PDF/AEE-Policies-to-Expand-Corporate-Access-to-Advanced-Energy.pdf. AEE is a national association of businesses, including many major energy customers such as Microsoft, Apple, Oracle, Amazon, Google, and Lockheed Martin.

[16] *In the Matter of Portland Gen. Elec. Co. Advice No. 19-02 New Load Direct Access Program*, Docket UE 358, Order 20-002 at 9 (Jan. 7, 2020) ("We expect development of [a resource adequacy] solution or requirement for direct access to be a top priority in the UM 2024 investigation.").

[17] *Id.* at 16 (recognizing that the allocation of costs associated with RPS compliance "is equally applicable . . . for all customers on direct access").

[18] *Id.* at 9 (suggesting that resource adequacy obligations may be placed "in the hands of customers").

- Ongoing costs associated with complying with legislative and Commission public policy mandates that require utility investments or other commitments in above-market resources.
- Ongoing cost of environmental compliance requirements for cost-of-service customers (unless direct access customers are required to comply with these requirements).
- Lost opportunity costs associated with diminished hosting capacity on the delivery system that could be utilized by potential new cost-of-service customers who make a contribution to fixed embedded costs.
- Cost shifts due to market depth issues if Energy Service Suppliers (ESS) are using up market depth or market liquidity rather than contributing to the construction of new capacity resources.

The potential benefits of a well-designed direct access program include the following:

- Increased customer choice.
- Potential deferral of planned resource acquisitions due to customer defection, assuming other specific conditions are also present.[19]
- Potential benefits of competition, which can increase utility incentives to keep costs low. As noted previously, however, if departing customers do not carry their fair share of historical or ongoing costs, this "competition" becomes cost-shifting.

A. What Are the Potential Cost Shifts?

Stranded Costs. When customers leave a utility's system to buy power from other sources, utilities may be left with unrecoverable long-term sunk costs incurred to meet the utility's obligation to serve all customers, including the departing customers.[20] As part of their obligation to serve, these utilities have already invested in existing generating plants, committed to long-term power and fuel contracts, and planned system expansions.[21] When customers leave the system, any unrecoverable long-term costs incurred to serve the departing customers will shift either to the utility, or to the utility's remaining customers. To prevent this cost shift, departing customers must be required to pay appropriate transition charges.

A transition charge is intended to account for these stranded costs, offset by the value of the energy freed up by the departing direct access customer.[22] For PacifiCorp, these costs are calculated annually in the Transition Adjustment Mechanism.

POLR Obligations. If utilities are required to serve as providers of last resort (POLR) for departing customers, a customer's election to return to the utility can create significant cost shifts to the electric customers who chose to remain. ESSs have argued that utilities can meet their

[19] *In the Matter of PacifiCorp dba Pacific Power Transition Adjustment, Five-Year Cost of Service Opt-out*, Docket UE 267, Order No. 15-060 at 5 (Feb. 24, 2015) (explaining PacifiCorp's position that there were no resource acquisitions to defer within the next 10 years, based on the Company's Integrated Resource Plan (IRP)).
[20] Wayne C. Turner and Steve Doty, *Energy Management Handbook*, 639 (The Fairmont Press, Inc. 2007).
[21] Turner & Doty at 639.
[22] Order No. 15-060 at 7.

POLR obligations to returning direct access customers through market-based purchases if necessary.[23] Given the tightening of capacity in the Northwest, however, the availability of market purchases at reasonable costs remains a risk factor in assessments of resource adequacy region-wide.[24]

Reliability Costs. Costs associated with short- and long-term grid reliability, including costs of investing in new generation and other reliability needs, may be shifted to utility customers if reliability obligations are housed with utility customers rather than fairly allocated between utility customers and direct access customers.[25]

Public Policy Costs / Costs of Other Mandates. Utilities are tasked with implementing legislative and Commission public policy mandates that may not be cost-effective, and thus have the potential to drive up costs and accelerate customer defection. These mandates may include legislative or Commission requirements for utilities to invest in technologies that are not yet cost-effective (e.g., early mandates to invest in batteries), to stand up programs that require extensive cost-subsidization (e.g., community solar), to enter into contracts that the utility may otherwise find non-competitive or carry the risk of disallowance (e.g., the Public Utility Regulatory Policies Act), to provide low-income assistance and other public policy funds to customers (e.g., SB 1149's public purpose charge), or to enhance the electric system in other ways that may not be cost-effective but may reflect changes in technology and public policy (e.g., distribution system planning). These public policy mandates, and others like them, increase the cost of utility service beyond the cost of competitive energy procurement and increase the risk of customer defection (and stranded costs) when third-party providers fail to carry these obligations in equal measure.

Other Costs. While costs of new generation continue to decline, costs of power delivery continue to increase. The addition of new competitive suppliers may require the addition of new transmission, additional costs to balance the system, and other BAA costs.

Market Failures / Reliability Failures. Unless the Commission's implementation of direct access includes robust mechanisms to assure the Commission has effective control over the issues noted above, regulatory gaps could create issues with availability or deliverability of resources. These issues can result in cost-shifts, as noted previously, but can also lead to market effects that amplify the risk of market shortages or, in extreme cases, load curtailment (brownouts or blackouts).

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[23] *See, e.g., In re Pub. Util. Comm'n of Or. Investigation into the Treatment of New Facility Direct Access Load,* Docket UM 1837, Initial Brief of Northwest and Intermountain Power Producers Coalition at 9-11 (Sept. 8, 2013).

[24] *See Wah Chang v. PacifiCorp,* Docket UM 1002, Order No. 09-343 (Sept. 2, 2009) (PacifiCorp customer signed special contract in 1997 giving it access to wholesale market prices during time of favorable wholesale energy prices, then unsuccessfully petitioned for a return to cost-of-service rates when, in the midst of the Western Energy Crisis, in a single month, customer paid nearly $5.9 million for energy that would have cost less than $500,000 under the standard tariff).

[25] *See* UCLA Luskin School of Public Affairs "The Promises and Challenges of Community Choice Aggregation in California," 33 (2019) (discussing the allocation of responsibility for grid reliability), available at: https://innovation.luskin.ucla.edu/wp-content/uploads/2019/03/The_Promises_and_Challenges_of_Community_Choice_Aggregation_in_CA.pdf.

Direct access without sufficient regulatory or market protections can disrupt markets.[26] The inelasticity of electric demand, combined with the need for the electric system to instantaneously balance supply and demand, can lead to volatility unless the system is protected by either (1) a competitive market with appropriate market monitoring rules (e.g., Texas), or by (2) robust ongoing regulatory mechanisms (e.g., Oregon, Nevada).

Since the Oregon Legislature retreated from movement to full retail deregulation, this Commission has followed a careful, incremental approach to direct access, one that has moved the state further toward its energy policy goals without threatening cost or reliability. Increased interest in direct access, the potential for capacity shortages in the near-term, and heightened policy-driven directives are risk factors for both cost and reliability.

B. What Are the Potential Benefits?

Increasing Customer Choice. A well-designed direct access program neither benefits nor harms utilities while providing customers with additional choices.

Deferring Planned Resource Acquisitions. In theory, it could be possible to defer some planned resource acquisitions due to customer departures, assuming other specific conditions are also present. The Commission has previously noted, however, that any such deferral must be demonstrated and cannot simply be assumed.[27] Given its obligation to serve, a utility must plan for customer needs significantly in advance of actual service.

Incentivizing Efficient Performance. In theory, competition could increase utility incentives to keep costs low. As noted previously, however, unless departing customers are required to carry their fair share of historical costs or ongoing costs for supporting state energy policy goals, this defection simply creates cost-shifting. Moreover, without a well-designed competitive market to establish market costs on an apples-to-apples basis for similarly situated market participants (such as Texas' market or certain FERC-jurisdictional Independent Systems Operator (ISO) /Regional Transmission Organization (RTO) markets), customers in vertically integrated states rely on state commissions to make and enforce policies that ensure that utility customers are held harmless from direct access implementation.

III. How Are Other States Handling Customer Choice and Access to Wholesale Markets for Different Customer Classes?[28]

The California Public Utilities Commission (CPUC) has identified a series of gaps associated with direct retail access to energy markets:

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[26] As noted previously, California's flawed implementation of customer-choice legislation led to disruption of electric markets across the West, exacerbating market scarcity and causing regional wholesale spot market prices to spike up to nearly $400/megawatt-hour (MWh) in December 2000, with average daily prices reaching nearly $1200/MWh. Spence, *supra,* at 427.

[27] Order No. 15-060 at 5-7.

[28] This section focuses primarily on other WECC states, per Commissioner Tawney's request. A matrix of which states affirmatively offer retail and wholesale market access is included in AEE's 2018 Report on Policies to Expand Corporate Access to Advanced Energy, beginning on page 25. The differences in programs and nomenclature for

- Provider of last resort obligations;
- Price disclosure;
- Data disclosure;
- General enforcement authority;
- Pricing of departing load;
- Market design and alignment with customer choice;
- Oversight, compliance and reliability responsibilities;
- Capacity and reliability.[29]

The Commission has asked for an assessment of how other states have responded to these issues.

Below is a brief summary of customer choice options in various Western Electricity Coordinating Council (WECC) states.[30] It appears that Oregon is one of the few Western states to have maintained direct access for a subset of retail customers in the wake of Western Energy Crisis. Oregon, California, and Nevada[31] are among the few states that have robustly engaged with many of the direct access issues listed above. However, other state commissions have touched on some of these concerns in the context of reviewing specific special contracts or tariffs for large utility customers, which can also impact other ratepayers.[32]

While it does not appear that any other state's approach to direct access provides a clear roadmap for Oregon, it is possible that certain specific elements of other state policies may be worth additional scrutiny as the focus in this docket becomes more granular.

A. Most Other WECC States Have Only Limited Direct Access to Wholesale Markets

1. *Idaho*

Idaho does not have a direct access program akin to Oregon's. While the Idaho Public Utilities Commission (IPUC) previously approved special contracts for large customers,[33] Idaho has since

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describing the various opportunities available to customers leads to come inconsistencies in reporting, with states like Oregon with partial deregulation described by various sources as states with retail access, no retail access, or partial retail access (or "choice").

[29] Cal. Pub. Utils. Comm'n, *California Customer Choice Project: Choice Action Plan and Gap Analysis* at 8-18 (Dec. 2018) available at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/Final%20Gap%20Analysis_Choice%20Action%20Plan%2012-31-18%20Final.pdf.

[30] PacifiCorp does not focus on California in this discussion, as the Commission is familiar with the CPUC's recent customer choice reports and has referenced them in public meetings. That said, further examination of California's policy decisions may be helpful as the issues in this docket become more granular.

[31] Arizona has considered elements of retail competition for years and continues to investigate issues such as community choice aggregation. *See* Quilici, Lisa M., et al., *Retail Competition in Electricity* at 13-14 (July 23, 2019) available at https://ceadvisors.com/wp-content/uploads/2019/07/AEPG-FINAL-report.pdf.

[32] *See, e.g.,* Quilici, *supra*, at 72-73, noting proliferation of "innovative products" currently being provided through utility green tariffs and other programs, even in states without retail competition.

[33] *In the Matter of the App. of PacifiCorp dba Utah Power & Light Co. for Approval of an Elec. Serv. Contract with Monsanto Co.*, Case No. UPL-E-95-4, Order No. 26282 (Dec. 1, 1995) (approving a new power supply agreement for the large customer based on the understanding that Monsanto could acquire alternative energy from a nearby municipal utility).

passed legislation precluding utilities from serving other entities' customers without the incumbent utility's permission.[34] The IPUC does not appear to have addressed the direct access or retail competition issues identified in this docket.

2. Montana

Montana does not have an existing direct access program. The Montana Legislature deregulated the retail electric market in 1997.[35] In light of market failures, the legislature re-regulated the industry and reestablished vertically integrated utilities in 2007. The legislature explained that the new legislation was due to (a) a lack of competitive markets for small customers and increasing exposure to higher market prices; (b) the distribution provider's lack of bargaining power when contracting for energy, due to its inability to self-supply generation; (c) the difficulty of planning for load given that the law provided for customer choice but no real competitive market existed; and (d) a need for more power to serve Montana customers.[36] Montana faces the same types of near-term capacity deficits that have been identified in the Pacific Northwest.[37]

3. Washington

Washington does not currently have formal "direct access," as Oregon defines it, but has previously allowed some degree of "retail wheeling" subject to the Washington Utilities and Transportation Commission's (WUTC) ongoing oversight. Because of this ongoing oversight, the WUTC does not have precisely the same issues Oregon does with respect to departing customers.

Retail wheeling developed in Washington in the mid-1990s, and allows a utility customer to contract with a third party to provide power, which is then wheeled to the customer over the utility's transmission and distribution facilities.[38] In 1999, as the country moved toward retail competition, Puget Sound Energy (PSE) developed Schedule 48 to provide large customers with access to "competitively priced electricity."[39] As energy prices spiked during the Western Energy Crisis, however, large customers who had signed onto the market-based tariffs appealed to the WUTC for relief. The WUTC approved a comprehensive settlement of complaints

[34] Idaho Code § 61-332 *et seq.* (Electric Supplier Stabilization Act).
[35] *In the Matter of the App. of PacifiCorp for Approval of its Elec. Util. Restructuring Transition Plan Filed Pursuant to Sen. Bill 390*, Docket No. D97.7.91, Order No. 5987b ¶ 13 (Sept. 22, 1997).
[36] Montana Dept. of Enviro. Quality, *Understanding Energy in Montana 2018* at 44 (2018) (summarizing committee minutes of House Bill 25 during the 2007 legislative session), available at: https://leg.mt.gov/content/Committees/Interim/2017-2018/Energy-and-Telecommunications/Understanding%20Energy%202018.pdf.
[37] *See* Northwestern Energy's 2019 Electricity Supply Resource Procurement Plan at 1-3 - 1-10, available at https://www.northwesternenergy.com/docs/default-source/documents/defaultsupply/plan19/ch-2019-vol-1-final.pdf.
[38] While the Washington legislature has a stated policy to encourage public utilities and cooperatives to enter into agreements to avoid unnecessary duplication of service facilities, this encouragement is non-binding. RCW 54.48.020; *see also Wash. Utils. and Transp. Comm'n v. Puget Sound Energy*, Docket UE-161123, Order 06 ¶ 22 (July 13, 2017) (describing Washington's retail wheeling).
[39] *Air Liquide America Corporation, et al. v. PSE*, Docket UE-981410, Fifth Supp. Order at 3 (Aug. 3, 1999).

between PSE and 12 large customers and terminated Schedule 48 on October 31, 2001.[40] Another retail wheeling tariff continues to apply to a handful of customers, but appears closed to new customers.[41] Outside of a single recent exception (described below), it does not appear that PSE has offered retail wheeling to new customers since shortly after the Western Energy Crisis.[42]

More recently, the WUTC approved a special retail wheeling arrangement in 2017, allowing Microsoft to purchase energy directly from alternative suppliers.[43] The WUTC approved the special contract with significant customer protection provisions to ensure that Microsoft's access did not result in "unreasonable or unaffordable rates for remaining customers, especially those least able to pay, or threaten the integrity, safety, reliability, and quality of the electric system and retail electric service."[44] Microsoft was required to pay transition fees, to comply with state RPS laws and public policy goals, and to assume the "risks and benefits of direct access to the wholesale market[.]"[45]

Washington's recent Clean Energy Transformation Act of 2019 (CETA) sets targets for reducing the carbon impact of energy resources serving Washington customers—requirements that apply to market customers as well.[46] The WUTC has been directed to promulgate rules by June 30, 2022, for "specification, verification, and reporting" requirements associated with retail electric load that is met with market purchases and to prevent double-counting of non-power attributes.[47] Rather than increasing customer retail choice, the legislature appears to recognize the need to ensure that the statute's mandates are not avoided by customers going to market to procure wholesale power that may not comply with the state's renewable energy goals.

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[40] *Air Liquide America Corporation, et al. v. PSE*, Dockets UE-001952 and UE-001959, Eleventh Supp. Order ¶ 31 (April 5, 2001) ("The essential thrust of Schedules 448 and 449 is to broaden significantly the power supply options available to PSE's industrial customers. In addition to self-generation options, a customer who takes service under Schedule 448 may arrange for one or more power suppliers other than PSE to make available to PSE power sufficient to meet the customer's load. Under Schedule 448, PSE will purchase power from the power supplier(s) on terms and at rates negotiated by the customer and the power supplier. PSE then will resell the power to the customer under a so-called Buy/Sell Contract without any mark-up or additional charges for the commodity, except for applicable state and local utility taxes."). *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-161123, Order 06 ¶ 25 (July 13, 2017) ("The Commission terminated Schedule 48 on October 31, 2001.").
[41] Docket UE-161123, Order 06 ¶ 25.
[42] *Id.* at ¶ 50 ("PSE has not offered retail wheeling to new customers in over 15 years[.]").
[43] *Id.* at 12.
[44] *Id.* at ¶ 91.
[45] *Id.* at ¶ 93.
[46] ESSB 5116, 66th Wash. Leg., Reg. Sess. (2019) (CETA), Secs. 4-5 (requiring market customers to comply with the requirement for electricity sales to be greenhouse gas neutral by 2030 and to be supplied by 100 percent non-emitting and renewable resources by 2045).
[47] CETA Sec. 13.

4. *Utah*

Utah does not have a direct access program, but instead provides opportunities for customers to select renewable energy options through utility-specific renewable energy tariffs.[48] For example, Rocky Mountain Power's Schedule 34 allows customers the option of contracting to have renewable energy purchased on their behalf. Such renewable energy tariffs were specifically authorized in Utah through 2016 legislation, which established Utah Code Ann. Ch. 17 Part 8 ("Renewable Energy Contracts"). The legislation requires renewable tariff customers to "bear all reasonably identifiable costs" that the utility incurs to deliver the power, including procurement, billing, and administrative costs.[49] This appears to be more akin to a utility "green tariff" than direct access to alternative suppliers.

5. *Wyoming*

Wyoming does not have a direct access program for retail energy customers. However, The Wyoming Public Service Commission has approved a Large Power Contract Service (LPCS) tariff for Cheyenne Light, Fuel and Power Company (Cheyenne) in anticipation of new large load from a single commercial customer—Microsoft.[50] The precise details of the contract between the parties remain confidential.[51] Cheyenne's LPCS tariff allows the utility to access Microsoft's own self-generated power supplies to meet the utility's peak demand needs, while allowing Cheyenne to purchase power from the market on Microsoft's behalf at a firm price to meet Microsoft's energy needs.[52] This appears to be more akin to a special tariff than direct access to alternative suppliers.

6. *Nevada*

Nevada has a form of direct access, known as "distribution only service" (DOS) for large utility customers.[53] Nevada initially pursued full deregulation in the 1990s, before returning to an integrated system following the Western Energy Crisis. However, Nevada has continued to allow large utility customers to apply to leave the regulated utility's system. This mechanism has only recently seen much interest, and the legislature responded in 2019 by tightening the

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[48] *In the Matter of Rocky Mountain Power's Proposed Elec. Serv. Sched. No. 34, Renewable Energy Tariff*, Docket No. 16-035-T09, Order Memorializing Bench Ruling Approving Settlement Stipulation (Aug. 18, 2016) (approving Rocky Mountain Power's Schedule 34).
[49] Utah Code Ann. § 54-17-805.
[50] *In the Matter of the App. of Cheyenne Light, Fuel and Power Co. for Authority to Establish a Large Power Contract Serv. Tariff*, Docket No. 0003-146-ET-15 (Record No. 14242), Memorandum Opinion, Findings and Order Approving Application (July 28, 2016).
[51] Docket No. 0003-146-ET-15 (Record No. 14242), Memorandum Opinion ¶ 46e.
[52] UtilityDive, "How Microsoft and a Wyoming utility designed a data center tariff that works for everyone," (Dec. 20, 2016) available at: https://www.utilitydive.com/news/how-microsoft-and-a-wyoming-utility-designed-a-data-center-tariff-that-work/430807/.
[53] *Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto*, Docket No. 19-06002, Order (Dec. 23, 2019) *reconsideration granted* Order on Rehearing (Feb. 14, 2020) (setting the case for rehearing to address the appropriate methodology for weather-normalization only).

requirements for departing customers. Other recent efforts to deregulate the state's power markets were defeated by the Nevada electorate in 2018.

In the mid-1990s, Nevada had moved towards full deregulation and a competitive energy market.[54] In 2001, Nevada returned to a vertically integrated system, with an exception for certain large customers.[55] At first, the program went largely unused, with only a few applications made before 2014.[56] Beginning in 2018, however, an additional 13 large customers applied to leave and become DOS customers.[57] In response, the 2019 Nevada legislature passed a bill restricting customers' ability to leave the utility's system. The bill also required the Public Utilities Commission of Nevada (PUCN) to implement additional customer protections.[58]

These changes were implemented to mitigate the impacts associated with too many organizations leaving the utility's system, including: (a) increased prices; (b) stressors on the grid as companies move between suppliers; (c) unpredictable demand; (d) evasion of public policy costs; (e) reduced renewable energy; and (f) shifting costs to residential customers.[59]

A recent effort to comprehensively overhaul and expand access to the competitive energy market was defeated in the 2018 election cycle.[60] The Natural Resources Defense Council, the Sierra Club, and other clean energy groups opposed the initiative, arguing that market restructuring would undermine existing decarbonization efforts.[61]

B. What Has Worked Well and What Has Not?

As demonstrated by the establishment and later repeal of retail competition in Montana and other states, increasing customers' access to the wholesale energy marketplace can be problematic

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[54] Pub. Utils. Commission of Nevada Presentation to the Governor's Committee on Energy Choice, "Historic Overview: Nevada Deregulation 1990's" at 4 (Nov. 7, 2017) available at: http://energy.nv.gov/uploadedFiles/energynvgov/content/Programs/TaskForces/2017/11-07-2017_EnergyChoice_Agenda6_PUCN%20Presentation.pdf.

[55] The new exception for large customers, known as NRS 704B, allows existing utility customers with 1 megawatt or more in average annual load to apply to depart the incumbent utility's system and obtain energy from an alternate provider. NRS 704B.080.

[56] *App. of Placer Turquoise Ridge Inc. as Operator of Turquoise Ridge Joint Venture to purchase energy, capacity and/or ancillary services from a provider of new elec. resources,* Docket No. 06-07026, Order (Dec. 05, 2006); *App. of Nevada Power Co. for approval of the Distribution Only Service Agreement with the Las Vegas Valley Water Dist. and the Colorado River Comm'n*, Docket No 06-03017, Order (Apr. 26, 2006); *App. of Barrick Gold U.S. Inc., operator of Cortez Joint Venture dba Cortez Gold Mines, to purchase energy, capacity, and/or ancillary services from a provider of new elec. resources*, Docket No. 08-03025, Order (July 11, 2008)

[57] The Nevada Independent, "Last-minute bill would severely curtail ability of businesses to leave NV Energy" (May 16, 2019), available at: https://thenevadaindependent.com/article/last-minute-bill-would-severely-curtail-ability-of-businesses-to-leave-nv-energy.

[58] SB 547, 80th Nev. Leg. (2019).

[59] Nev. Sen. Committee on Growth and Infrastructure, Presentation by Senator Chris Brooks, Dist. No. 3, "SB 547: A History of NRS 704B and Energy Deregulation in Nevada" at C14 (May 23, 2019), available at: https://www.leg.state.nv.us/Session/80th2019/Exhibits/Senate/GRI/SGRI1295C.pdf.

[60] The Nevada Independent, "Voters reject energy choice ballot question, as other initiatives advance on comfortable margins" (Nov. 7, 2018) available at: https://thenevadaindependent.com/article/voters-reject-energy-choice-ballot-question-as-other-initiatives-advance-on-comfortable-margins.

[61] UtilityDive, "Green groups come out against Nevada retail choice ballot measure," (July 27, 2018) available at: https://www.utilitydive.com/news/green-groups-come-out-against-nevada-retail-choice-ballot-measure/528729/.

unless carefully implemented. Some WECC states have retreated from retail access (like Montana); others appear to rely more heavily on specific supply offerings such as utility green tariffs rather than customer departures to implement customer choice; and still others, like Nevada and California, continue to struggle with the implementation of their retail access programs, which, like Oregon's, are partially deregulated and create a fragmented regulatory scheme.

In states that completely deregulated their retail electric markets, like Texas, vertically integrated utilities were often required to spin off their generating assets, and their stranded costs were determined through the market sale of generating assets, other specific valuation methods, or through quasi-judicial administrative hearings. Those stranded costs, and other costs associated with above-market and public policy goals, were generally made non-bypassable and recoverable over time through charges on the distribution utility's system.[62]

In states like Oregon, however, with partially deregulated retail markets, assessments of stranded costs (and other ongoing costs needed to prevent cost-shifting) must be made accurately and repeatedly year-after-year, in the face of continued advocacy for the removal of such charges.

In short, the complex, multi-level regulatory schemes of partially deregulated markets can create vexing issues in partially deregulated states like Oregon, California, and Nevada, where, instead of tackling the issues of cost shifting in a holistic and dispositive manner, state commissions are tasked with continually addressing the transitional issues related to the partial and potentially temporary migration of customers, while still maintaining a fair and functional regulated market.

C. How Can These Findings Be Applied to Oregon, Including Consideration of the Fact That Oregon's Direct Access Market Is Limited to Non-Residential Customers?

As the previous discussion indicates, there are few WECC states with records of successful, widespread direct access implementation.

Because direct access options in Oregon are limited to non-residential customers, this Commission is relieved of the burden of developing the complex customer protection requirements that would be necessary if direct access were extended to residential customers (as in California). Because direct access customers in Oregon are sophisticated business entities, they can and should be expected to bear the risks associated with their economic decisions to leave and/or come back to the utility.

Despite limiting direct access to non-residential customers, the costs and risks of direct access remain substantial. Mitigating these risks and allocating these costs will require careful assessment of transition charges, clear allocation of responsibility for the state's POLR, reliability, and resource adequacy needs, as well as ongoing cost allocation flexibility as technologies and state policies require continued system, resource, and remediation investments.

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[62] *See, e.g. Tex. Indus. Energy Consumers v. CenterPoint Energy Houston Elec., LLC*, 324 S.W.3d 95, 104 (Tex. 2010) (describing key elements of deregulatory scheme).

PacifiCorp looks forward to addressing these issues in more detail during the course of this investigation.

IV. Resource Adequacy

A. What Is Resource Adequacy?

Resource adequacy means that a Balancing Authority (BA) or other entity with responsibility for maintaining resource balance in a particular region has enough resources to serve load across a wide range of conditions and with a sufficient degree of reliability.[63] The North American Electric Reliability Corporation (NERC)—the FERC-certified Electric Reliability Organization that, among other things, enforces reliability standards and oversees WECC—defines resource adequacy as "[t]he ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[64]

Typically, the time span over which resource adequacy is measured is 1-4 years. "Resource sufficiency," by contrast, requires a utility to have sufficient operating reserves to ensure reliable operation of the grid on day-to-day basis.[65] IRPs look at yet another time horizon: the utility's ability to meet its future loads over a time period of 20 years or more.

NERC has explained that the bulk-power system achieves an adequate level of reliability when it possesses the following characteristics:

1. The system is controlled to stay within acceptable limits during normal conditions;
2. The system performs acceptably after credible contingencies;
3. The system limits the impact and scope of instability and cascading outages when they occur;
4. The system's facilities are protected from unacceptable damage by operating them within facility ratings;
5. The system's integrity can be restored promptly if it is lost; and

[63] NERC, *Glossary of Terms Used in NERC Reliability Standards* at 4 (updated Feb. 24, 2020) (defining "Balancing Authority"), available at: https://www.nerc.com/files/glossary_of_terms.pdf. A BA is responsible for maintaining resource balance within a particular region, known as a BAA. *Id.*
[64] NERC, *Glossary of Terms Used in NERC Reliability Standards* at 1
[65] Northwest Power Pool (NWPP), *Exploring a Resource Adequacy Program for the Pacific Northwest* at 44-45 (Oct. 2019) (distinguishing resource adequacy from resource sufficiency), available at: https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf.

6. The system has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.[66]

B. How Is It Provided?

BAs are required not only to maintain sufficient resources to serve anticipated customer load, but also to procure additional "planning reserves" *not* intended to serve customer load on a regular basis, but to be held back to ensure there are sufficient resources available to serve load even in unexpected conditions. The amount of planning reserves needed may be determined in a number of ways, but an important element often includes setting a planning reserve margin PRM or determining an acceptable loss of load probability associated with a certain set of loads/resources and contingencies.[67]

Importantly, resource adequacy is an issue that needs to be addressed in advance, not after it becomes a problem. Electricity is unlike other consumer products in a number of ways, but critically in this context; in order for the grid to function, grid operators must instantaneously balance supply and demand. They must do so while being constrained by the physical limitations of the system to deliver power to any particular point on the grid. A failure to achieve this instantaneous balancing in one location can threaten the stability of the entire grid.[68] Grid management challenges are further exacerbated by the increasing diversity and intermittency of renewable resources and the pressures to move away from fossil fueled generation resources.

Despite the need for this balance, both consumer demand for electricity and the availability of electric generation supply (once output nears capacity) are relatively inelastic.[69] Load shedding means blackouts, a result that is anathema to public policy, and yet new generation resources that can provide power at precisely the time customers need them do not appear on demand. Such resources take time to plan and build.

Consequently, BAs must plan to have adequate, firm resources available for system needs to ensure system failure does not occur when something goes wrong.

C. What Regulatory Requirements or Market Structures Are Used in Other States with Direct Access to Ensure Resource Adequacy?

Resource adequacy can be a concern for a region even in the absence of direct access. Direct access simply complicates and adds additional strain to a region's existing resource adequacy

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[66] NERC, *Definition of "Adequate Level of Reliability"* at 6 (Dec. 2007) (emphasis added) (stating the definition of "Adequacy" in the May 2007 NERC Glossary of Terms), available at: https://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.
[67] NWPP, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 13.
[68] Severin Borenstein, *The Trouble With Electricity Markets: Understanding California's Restructuring Disaster*, 16 J. of Econ. Perspectives 1, 195-96 (2002), available at: http://faculty.haas.berkeley.edu/borenste/download/JEP02ElecTrbl.pdf; Spence, *supra*, at 439-440.
[69] *Id.*

concerns because, in the absence of compelled resource adequacy obligations for third parties, third-party providers are financially incentivized to procure only enough energy and capacity to serve their customers; they have no incentive to procure the additional planning reserves needed to meet appropriate resource adequacy standards.

In the absence of strong regulatory controls, then, these providers may "lean" on regulated utilities or other load-serving entities as a (potentially expensive) backstop, or they may simply rely on electricity markets to provide "extra" resources when contingencies occur. Both of these scenarios have the potential to increase utilities' costs of serving customers and may even threaten reliability if the resources needed to meet contingencies simply do not materialize.

There are a number of ways that resource adequacy is regulated:

- The Pacific Northwest. In the Pacific Northwest, investor-owned utility resource adequacy needs are generally addressed by individual utilities through state commission resource-planning processes (typically, IRPs), followed by utility resource procurements.

  While utility-by-utility planning has been reasonably effective, recent developments in the electric sector have led to projections of near-term regional capacity deficits. The downside of siloed, individual assessments of resource adequacy is that utilities are unable to take advantage of wider resource pooling, diversity benefits, and greater visibility into regionwide market depth and/or resource availability that might be possible with increased coordination. Without access to wider information, individual utility assessments of market depth may be incorrect, or multiple areas may be relying on the availability of the same market purchases or the same resources (double-counting) for resource adequacy purposes. This risk is exacerbated if third-party providers like ESSs intend to rely on market purchases, or expect utilities to do so, to cover any type of resource shortfalls for either direct access customers or for customers returning to the utilities' systems.

  More recently, the NWPP, a reserve sharing group comprised of multiple utilities across the Western Interconnect, has been studying a voluntary program that would allow electric utilities to forecast and manage resource adequacy in a coordinated manner. By planning as a group, participating utilities would have a clearer understanding of the resource adequacy of the region, thereby better informing resource acquisition decisions.[70]

- ISO/ RTO Capacity Markets. Some ISOs/RTOs, such as PJM and ISO New England, operate centralized capacity markets for procurement of resource adequacy needs. These markets are highly FERC-regulated and have recently been the subject of significant

[70] *See, e.g.,* NWPP, *Status of Resource Adequacy Program for NWPP Members and Stakeholder Engagement Opportunities* (Jan. 3, 2020), available at: https://www.nwpp.org/private-media/documents/2020.01.03_NWPP_RA_Stakeholder_Engagement_Public_Document.pdf.

litigation between the states and FERC, due to friction between state-specific resource procurement policies and FERC's interest in federally regulated price competition.[71]

- Other ISO/RTO Resource Adequacy Programs. Other ISOs/RTOs, like the Southwest Power Pool (SPP), have resource adequacy programs that are also FERC-regulated, but are largely bilateral in nature and provide more flexibility for state resource procurement policies. SPP, for example, provides consistent metrics across its footprint to assess regional and sub-regional resource adequacy, allocates responsibility for procurement to member utilities, and qualifies resources that wish to be considered for the program. Utilities meet the resource adequacy obligations assigned to them by SPP by procuring new resources or through bilateral contracts. The public utility commissions of the member states have a significant influence on SPP's resource adequacy program and member utilities have flexibility in procuring various types of resources to meet their resource adequacy needs.[72]

- California's Resource Adequacy Program. California has a resource adequacy program that, like SPP's, is largely based on bilateral contracts or individual utility procurements. The CPUC, California Energy Commission (CEC), and the California ISO (CAISO) jointly implement the program. The CPUC calculates resource adequacy needs, allocates those needs among the state's load-serving entities, establishes common capacity counting, and enforces compliance. CAISO has the authority to procure backstop capacity, while the CEC oversees resource adequacy for publicly owned utilities.[73] The California resource adequacy program is currently being evaluated by both the CPUC as well as through CAISO's implementation of the resource adequacy program.[74] Both of these efforts to revamp the resource adequacy program reflect the changes in California's grid relative to solar and wind penetration as well as recent retirements in gas generation.

Like many issues in the electric industry, resource adequacy is not a major subject of discussion when resources are plentiful, deliverability is straightforward, and compliance is affordable and manageable from a regulatory perspective. When resource adequacy becomes threatened, however, the issues become more complicated, and regulatory solutions have proven to be challenging in many regions.

PacifiCorp looks forward to a meaningful exploration in this docket of options to ensure that all providers are subject to robust and enforceable requirements to carry their fair share of resource adequacy obligations.

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[71] *See, e.g., Calpine Corp. et al. v. PJM Interconnection, LLC*, 163 FERC ¶ 61,236 (2018) (rejecting PJM's capacity market proposal).
[72] NWPP, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 37.
[73] NWPP, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 69.
[74] *See, e.g., Order Instituting Rulemaking to Oversee the Resource Adequacy Program*, R-17-09-020, Application for Rehearing of Decision 19-10-021 of the CAISO (Nov. 18, 2019) (seeking reconsideration of the CPUC's decision addressing resource adequacy import rules).

D. Why Is It Important or Not Important?

Resource adequacy is critical to the continued reliable operation of the grid. If resources are insufficient to cover a range of contingencies, any number of events can create price volatility or even customer load curtailments. A system that plans appropriately for resource adequacy can successfully operate in the event of generation outages, storm damage, unexpected weather, or any number of occurrences. A system that does not plan appropriately for resource adequacy may need to rely on exorbitantly expensive purchases to continue operation when these events occur, or it may simply need to shut down.

The Northwest Electric Power and Conservation Council explained it succinctly:

> The Western Electricity Crisis of 2001-2002 <u>is widely believed to have had its roots in resource inadequacy</u>. For a number of reasons, resource development in the 1990s failed to keep pace with growth in the region and, in fact, the entire West. When poor hydro conditions manifested themselves in the summer of 2000 and on into 2001, the underlying tight supply was made apparent and wholesale prices went out of control. The lights never went out in the Northwest during 2000 and 2001 but the region experienced extremely high wholesale prices. This occurred even though large amounts of load, mostly from the Direct Service Industries, were taken off the system.[75]

The Western Energy Crisis centered on California markets and resulted in blackouts across the state. Although its ripple effects did not lead to blackouts in the Pacific Northwest, it had a significant impact on Oregon's economy and permanently decimated the Northwest's aluminum industry.[76]

The state's economy and the health of its citizens depend on a reliable, affordable electric supply that allows businesses to operate, schools to remain open; lights, refrigerators, and elevators to continue running; and medical equipment to continue functioning. Resource adequacy plays an important role in ensuring the reliability of this supply.

E. What Direct Access Issues May/Should Be Considered in the Contested Case Phase?

PacifiCorp believes this question may be more constructively answered after the parties complete comments and briefing. Comments and briefing may allow the parties to better identify areas of agreement (or disagreement) on this issue, and whether there are consensus areas that limit the scope of issues in need of evidentiary support. In addition, the ongoing efforts to stand up a regional plan for resource adequacy may be further along by the time comments and briefing are completed, which may also inform the parties' discussions.

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[75] Northwest Power and Conservation Council, *The Fifth Northwest Electric Power and Conservation Plan*, Vol. 2, Ch. 8 at 8-1 (May 2005) (emphasis added), available at: https://www.nwcouncil.org/sites/default/files/_08__Resource_Adequacy_1.pdf.
[76] *See* Northwest Power and Conservation Council, *Aluminum* (2020) available at https://www.nwcouncil.org/reports/columbia-river-history/aluminum.

As mentioned above, there are multiple current efforts within the Western region to review resource adequacy given the changing landscape of resource portfolios and announced resource retirements. It will be crucial for Oregon parties to stay engaged in the regional efforts and to recognize that an Oregon resource adequacy framework for direct access customers may need to be revisited to ensure consistency between a potential regional program and the state program. PacifiCorp supports the efforts of the Commission to provide guidance and clarification on the resource adequacy obligations of direct access customers, as it believes this will ultimately provide a more fair and equitable allocation of the costs associated with reliable grid operations.

V. Conclusion

PacifiCorp appreciates the opportunity to file these comments and looks forward to engaging on these and other issues in this docket.[77]

Respectfully submitted this 16th day of March, 2020.

By: ______________________
Matthew McVee
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[77] The first phase of this docket is a comment phase, with reply comments to be filed on April 6, 2020. The second phase is currently envisioned to be a legal-briefing phase, followed by a contested-case phase.